8.0 Conclusions

Based on the results presented for the period from January 1, 1981 through December 31, 1990, the following conclusions have been drawn regarding California's regulated hazardous liquid pipelines. These conclusions have been organized into two subsections. The first includes items which we consider to be major findings, as well as the issues specifically required to be addressed in the study by state statute. The second subsection includes what we consider to be less significant findings.

8.1 Significant Findings

a. Overall Incident Rates

The various criteria used to report hazardous liquid pipeline incidents had a direct effect on the resulting incident rates. The data collected regarding California's incidents was the only completely audited sample available. It resulted in incident rates somewhat higher than those presented in other studies. Using all of the available data, we have estimated the overall incident rates for various pipeline events as follows:

Event	Incident Rate
any size leak	7.1 incidents per 1,000 mile years
damage greater than $5,000	1.3 to 6.2 incidents per 1,000 mile years
damage greater than $50,000	up to 4.4 incidents per 1,000 mile years
any injury, regardless of severity	0.70 injuries per 1,000 mile years
injury requiring hospitalization	0.10 injuries per 1,000 mile years
fatality	0.02 to 0.04 fatalities per 1,000 mile years

b. External Corrosion

External corrosion was by far the largest cause of incidents, representing 59% of the total. Significant differences in external corrosion leak incident rates were found among the following factors:

- Older pipelines had a significantly higher external corrosion incident rate than newer lines.

- Elevated pipeline operating temperature significantly increased the frequency of external corrosion caused leaks.

- Intrastate lines had a much higher external corrosion rate than interstate pipelines. However, the intrastate lines were generally much older and operated at a higher mean operating temperature.

- Non-common carrier lines had a much higher external corrosion rate than common carrier pipelines. But the non-common carrier lines operated at a higher mean operating temperature and were older.

- Crude oil pipelines had a much higher external corrosion rate than petroleum product pipelines. Once again however, crude pipelines had a much higher mean operating temperature and were slightly older.

- Pipelines within standard metropolitan statistical areas (SMSA) had a higher external corrosion incident rate than pipelines in non-SMSA's. Data was not available to further analyze this difference.

- The external corrosion incident rate was significantly less for pipelines greater than 16" in diameter than it was for smaller lines.

- Although a small sample, pipelines without cathodic protection systems had a drastically higher frequency of external corrosion caused leaks than protected lines.

- In some cases, the pipe specification affected external corrosion incident rates.

- Significant external corrosion incident rate differences were found between various pipe coatings. Although pipe age and operating temperature also affected these results, coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as bare pipe. Extruded polyethylene with side extruded butyl coated pipe had the lowest external corrosion rate, one-fifth that of coal tar or asphalt enamel wrapped pipe.

It is likely that many of the older lines included in the study had inadequate cathodic protection, by current standards, during their early years of operation. The regulatory requirements for these lines has increased during their operating life. For instance, although some interstate line regulations date back to 1908, many externally coated interstate lines were not required to be cathodically protected until 1973; many externally coated intrastate lines were not required to be cathodically protected until 1988. Further, intrastate lines operating by gravity or less than 20% SMYS were not required to have cathodic protection until 1991.

c. Railroad Effects

There was virtually no difference between the incident rates for pipelines within 500' of a rail line and pipelines away from rail lines. Further, the average spill size for pipelines within 500' of a rail line was roughly one-third the average spill size for other lines. However, the average damage was much higher for incidents near rail lines.

d. Incident Rate Trends

The data indicates a slightly decreasing incident rate trend during the ten year study period. The ordinary least squares line of best fit indicated that the incident rate was decreasing at the rate of 0.52 incidents per year, per 1,000 mile years of pipeline operation during the study period.

Although the average damage per incident varied widely for each year during the study period, the ordinary least squares line of best fit indicated an increasing trend in average damage per incident during the ten year study period. After normalizing the data to constant 1983 US dollars, the ordinary least squares line of best fit indicated that the average cost per incident increased at the rate of $33,040 per year. The average damage during the study period was $141,000 per incident. However, the median damage was only $7,200 per incident, indicating that a relatively small number of very high damage incidents significantly skewed the average value.

e. Seismic Activity

We anticipate somewhere between 13 and 29 incidents caused by seismic activity on regulated California hazardous liquid pipelines during a future 30 year period. Extrapolating injury and fatality data collected in this study, we would expect seismic activity to cause between one and three injuries and have between a 1 in 6 and 1 in 13 likelihood of causing a fatality during a future 30 year period.

The reader should note that these injury and fatality extrapolations were based on a very limited data sample; their statistical relevance is very limited. Further, for the purposes of this study, data were included in the injury category, regardless of severity; this included injuries which required only minor on-site medical treatment and/or observation. As a result, we expect that any injury data presented herein is conservative, when compared to more typical injury definitions.

f. Block Valve Effectiveness

The median and average block valve spacing on California's regulated hazardous liquid pipelines were 1.39 and 3.12 miles respectively. The median maximum potential drain down length of pipe was 3.4 miles for the incidents with block valve data available. 50% of the spill volumes represented less than 0.75% of the maximum potential drain down volume between adjacent block valves.

We found little or no statistical correlation between spill size and block valve spacing. However, the ordinary least squares line of best fit indicated that reducing block valve spacing would result in a 31 barrel spill volume reduction per mile of block valve spacing reduction (data normalized for 12" nominal diameter pipe). Using this data, if the number of block valves were doubled on California's regulated hazardous liquid pipeline systems by adding 1,909 valves, the average block valve spacing would be reduced from 3.12 miles to 1.76 miles. This would result in only a 13% reduction in overall average spill volumes. We estimate that this would in turn result in only a 1% to 3% reduction in overall average damage values.

We believe that the costs associated with the last barrels spilled are far less than the first few barrels spilled; but we were unable to quantify this relationship. As a result, we performed cost benefit analyses assuming various values for this relationship. The cost benefit analyses regarding adding block valves to California regulated hazardous liquid pipelines, assuming a 10% value for this unknown, are presented below:

	250 Valves	500 Valves	1,000 Valves	1,909 Valves
Estimated Cost (Present Value)	$8,750,000	17,500,000	35,000,000	66,815,000
Estimated Benefit (Present Value)	$402,000	737,000	1,261,000	1,907,000

Cost Benefit Ratio	21.8:1	23.7:1	27.7:1	35.0:1

Similar analyses were performed considering six 12" nominal diameter pipeline segments ranging from one to ten miles long. The cost benefit ratios for the various effectiveness factors for adding an intermediate block valve to these segments are shown below.

Segment Length	10% Factor	25% Factor	50% Factor
1 Mile	384 : 1	153 : 1	76.8 : 1
2 Miles	96.0 : 1	38.4 : 1	19.2 : 1
3 Miles	42.7 : 1	17.1 : 1	8.54 : 1
4 Miles	24.0 : 1	9.60 : 1	4.80 : 1
5 Miles	15.4 : 1	6.15 : 1	3.07 : 1
10 Miles	3.84 : 1	1.54 : 1	0.77 : 1

This data indicates that there may be some justification for additional block valves on very long segments of pipeline. However, natural terrain and other factors affect each situation differently. As a result, each case should be investigated individually.

Several other studies have evaluated the possibility of adding and/or converting to remotely or automatically controlled valves. These studies generally agree that automatically controlled valves are unreliable and are not recommended. They also agreed that any benefits associated with remotely controlled valves could not be realized without effective SCADA systems with leak detection subsystems. One study found a favorable cost benefit ratio for remotely actuated block valves in urban areas. However, this study assumed that remotely controlled valves would result in a 75% reduction in all safety and environmental accident effects. We believe the actual reduction to be much lower than this value. The other studies found cost benefit ratios of 15 - 18:1 for converting existing manually operated block valves to remotely controlled operation.

g. Pipe Age

Pipe age had a significant effect on the resulting overall incident rates. These values ranged from a high of 19.7 incidents per

1,000 mile years for pipelines constructed before 1940, to less than one incident per 1,000 mile years for pipe constructed in the 1980's. All of our statistical analyses indicated a very strong relationship between decade of construction and the resulting incident rates. Most of this variation was caused by differences in the external corrosion incident rate as described earlier.

h. Operating Temperature

There was a direct relationship between normal operating temperature and the resulting external corrosion incident rate. As operating temperature increased, the frequency of external corrosion caused incidents increased as well. We did not find a correlation between operating temperature and other incident causes. All statistical analyses indicated a very strong relationship between operating temperature and external corrosion incident rates.

i. Fire Department Notification

Our survey of pipeline operators and local fire departments yielded a consensus that notifying local affected fire agencies each time pipeline fluid contents changed would not result in significant benefits. The fire departments surveyed indicated that their current programs and contingency plans were adequate to handle foreseen emergencies.

j. Operating Pressure

We did not find a statistical correlation between normal operating pressure and the probability of rupture.

8.2 Less Significant Findings

The less significant study findings are listed below:

- 94% of the injuries and 100% of the fatalities resulted from three incidents (0.58% of the total) during the ten year study period. Each of these incidents had a different cause. Although the number of incidents was too small to draw any meaningful conclusions, it was interesting to note that all of the injuries and fatalities occurred on petroleum product pipelines. (Once again, the reader should be cautioned against drawing any potentially misleading conclusions from this limited data sample.)

- California's high risk pipeline program has been effective in identifying pipelines with a higher than average leak incident rate.

However, the increased hydrotesting requirements placed on these lines did not clearly result in a reduction in incident rates during the study period.

- We were unable to identify a clear relationship between hydrostatic testing frequency and the resulting leak incident rate. It was interesting to find that the most frequently hydrostatically tested pipe had the highest leak incident rate; however, this sample was also the oldest pipe and operated at the highest mean operating temperature.

- 58% of the regulated California hazardous liquid pipelines are capable of being *smart* pigged with little or no modification. 70% of these lines have already been inspected in this manner. Although pipelines which had been internally inspected using *smart* pigs had the lowest overall incident rates, they were also by far the newest.

- Intrastate pipelines had an overall incident rate roughly three times greater than for interstate lines. However, the intrastate lines were on average 13 years older and operated at a mean operating temperature nearly 30°F higher than the interstate lines. The differences between common carrier versus non-common carrier lines had similar results, with the non-common carrier lines having the higher incident rates. In both cases, differences in external corrosion incident rates comprised most of the difference.

- Crude oil pipelines had an overall incident rate of 9.89 incidents per 1,000 mile years. This was over twice as high as the incident rate for product pipelines. However, the operating temperature for the crude lines was 23°F higher. Once again, the differences in the external corrosion rates caused most of the difference.

- The incident rate for pipelines within standard metropolitan statistical areas (SMSA) was over three times higher than for non-SMSA areas. However, the average damage and spill size for incidents within SMSA's was less than one-third of the values for non-SMSA's.

- Pipe diameter had an effect on the external corrosion incident rate. Generally, as pipe diameter increased, the external corrosion rate decreased.

- There was no statistical difference between the leak incident rates for pipelines with sacrificial anodes versus impressed current cathodic protection systems. However, unprotected lines had an external corrosion leak incident rate over five times higher than for protected lines. We did not find a statistical correlation between the frequency of cathodic protection surveys and the external corrosion incident rate.

- 78% of California's regulated hazardous liquid pipe was constructed of ASTM X-Grade material. This class of pipe had the lowest overall leak incident rate (4.13 incidents per 1,000 mile years). However, pipe age and operating temperature differences also affected the results of this investigation.

- Lap welded pipe, which comprised 4% of the total, had an extremely high leak incident rate of 50 incidents per 1,000 mile years. However, this pipe type was also the oldest of the group, with a 1933 mean year of construction.

- There does not appear to be a fluctuation in the frequency of incidents throughout the year.

- 87% of the leaks occurred in the pipe body. 3.1% occurred at valves. 2% were caused by longitudinal weld seam failures. 1.6% were caused by leaks at welded fittings.

- 27% of the incidents resulted in spill volumes of one barrel or less. The median spill size was five barrels. However, the mean spill size of 408 barrels was influenced by a relatively small number of large spills.